# NTTG 2016-2017 DRAFT REGIONAL TRANSMISSION PLAN

## December 30, 2016

# I. Executive Summary

The objective of the Northern Tier Transmission Group ("NTTG") Draft Regional Transmission Plan ("dRTP") is to evaluate from a regional perspective whether NTTG's transmission needs may be satisfied on a regional or interregional basis more efficiently or cost effectively than through local planning processes. This biennial planning cycle implements the FERC Order 1000 interregional provisions for the regional and Interregional Transmission Projects ("ITP" or "ITPs") submitted to NTTG during its quarter one (January-March 2016) data collection process.

During the first year of the NTTG 2016-2017 biennial planning cycle, the Technical Work Group ("TWG") of the NTTG Planning Committee evaluated the prior Regional Transmission Plan (pRTP) developed in the 2014-2015 planning cycle, the Initial Regional Transmission Plan ("IRTP")[1] and a number of Change Case[2] plans that included non-Committed regional projects and Interregional Transmission Projects to determine a most efficient or cost-effective plan which becomes the Draft Regional Transmission Plan ("dRTP"). The evaluation considered the facilities submitted by the Transmission Providers as well as the Interregional Transmission Projects submitted in Q1. This dRTP selection was made by conducting power flow studies to perform a reliability analysis of the pRTP case, the IRTP case and each Change Case under seven stressed conditions and by performing an economic analysis of the pRTP, the IRTP and those Change Case plans that reliably meet NTTG's transmission needs. The power flow stressed conditions consisted of: NTTG summer peak, NTTG winter peak, high flows on the Idaho to Northwest path for both southern Idaho imports and exports, Montana to the Northwest path westbound transfers, north to south flows across TOT2, and a high Wyoming Wind scenario. The economic analysis examined three key metrics -- capital-related costs, NTTG area loss benefits, and reserve sharing benefits.

[1] The IRTP includes projects in the prior Regional Transmission Plan, projects in the Funders Local Transmission Plans, and accounts for future generation additions and deletions (e.g., announced coal retirements).

[2] A Change Case is a scenario where one or more of the Alternative Projects is added to or replaces one or more non-Committed Projects in the IRTP. The deletion or deferral of a non-Committed Project in the IRTP without including an Alternative Project can also be a Change Case.

The Change Case plans were created by removing the non-Committed projects[3] from the IRTP and adding in any number of Alternative Projects[4] to be evaluated through technical evaluation. The TWG determined that four non-Committed regional projects must be included in the dRTP - the Boardman to Hemingway ("B2H") project, the Energy Gateway ("EG") projects (both Gateway West and Gateway South) and Antelope Transmission Projects. The addition of these four projects are necessary for acceptable system performance. The Null Change Case power flow study results showed that system performance was acceptable in only one of the seven stress conditions studied, the Heavy Winter case, without these four non-Committed projects and no Alternative Projects. The high southern Idaho import case showed the need for the B2H project to transfer up to 1000 MW of load service obligations. The southern Idaho export case and the high Wyoming wind case demonstrated the need for the EG projects. The 540 MW (net) nuclear resource[5] when developed at the Idaho National Lab also showed acceptable system performance with the non-Committed projects included.

The TWG technical study discovered that the 2014-2015 pRTP that included two non-Committed projects (B2H project and a portion of the EG project) was not reliable. The study also established that the amount of new Wyoming wind that is added over time impacts the transmission system reliability west of Wyoming. To arrive at this conclusion the TWG evaluated 23 Change Cases that fully explored the need for the non-Committed projects in the IRTP, pRTP and the three proposed Interregional Transmission Projects. Stepping through its reliability study process the TWG winnowed the number of potential dRTP cases to three – the IRTP and two the variants of the IRTP (Change Cases 21 and 23[6]). These Change Cases were created to explore the relationship of the Wyoming wind buildout and its impact to transmission



[3] A non-Committed project is a planned project whose right-of-way has not been fully secured.

[4] Alternative Projects collectively refers to Sponsored Projects, projects submitted by stakeholders, projects submitted by Merchant Transmission Developers, and unsponsored projects identified by the Planning Committee (if any).

[5] It is assumed that interconnection of the nuclear generation to the transmission system includes two new 345 kV lines from Antelope to Goshen and from Antelope to Borah (previously referred to as the Antelope Transmission Projects).

[6] Change Case 21 is similar to the IRTP but excludes the Midpoint-Hemingway #2 and the Midpoint-Cedar Hill 500 kV lines. Change Case 23 was taken from Change Case 21 and also excludes the Populus-Borah 500 kV line. Both Change Case 21 and Change Case 23 are staged versions of the IRTP, for the transfers studied, these lines segments did not significantly improve system performance. At higher transfer levels, these additional segments or an alternative would be necessary.

system reliability west of Wyoming and a potential incremental buildout of the Gateway West project.

Three Interregional Transmission Projects (ITP or ITPs) were studied -- the SWIP-North Project (Midpoint to Robinson Summit), the Cross-Tie Project (Clover to Robinson Summit) and the TransWest Express Project (Aeolus area to southern Nevada). As described in NTTG 2016-17 Study plan, the evaluation of the three ITPs was conducted in the context of ITP joint interregional coordination with the other Regional Planning entities and NTTG's regional planning process as Alternative Projects. NTTG coordinated its planning data with the other Relevant Regional Planning entities and will also coordinate its dRTP ITP study results with the other Regional Planning entities. Each ITP, in combination with other ITPs and/or non-Committed regional projects, were analyzed through Changes Cases as a possible replacement for one or more of the IRTP non-Committed projects (e.g., B2H and/or EG). It was determined that none of the ITPs could replace or augment the non-Committed Projects such that NTTG's regional transmission needs were satisfied from a regional perspective on a more efficient or cost effective basis.

An economic analysis of the IRTP and Change Cases 21 and 23 was conducted after completing the reliability analysis. The economic analysis compared the annualized incremental costs of the IRTP and the two Change Cases[7]. The annual incremental cost was computed as the sum of three metrics - the capital related costs, monetized energy loss benefit and monetized reserve benefit. The following figure displays the results of the incremental cost analysis.



[7] Note, the Antelope Transmission Project was not considered in the economic analysis due to the local nature of the project.

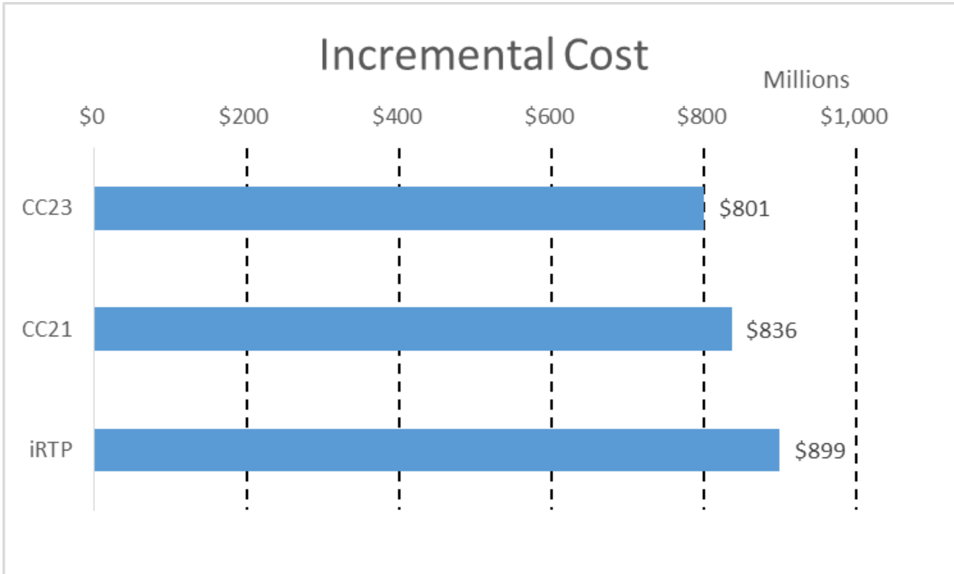



**Figure 1 – Summary of Incremental Costs for 2026 NTTG Study Cases**

Based on the reliability and economic considerations for the transfers studied, the most efficient and cost effective draft plan is the Change Case (CC23) which is comprised of the IRTP with the following non-Committed projects removed:

- Midpoint-Hemingway #2 500 kV
- Midpoint-Cedar Hill 500 kV
- Populus-Borah 500 kV

# II. Introduction

The NTTG 2016-2017 Draft Regional Transmission Plan was developed in accordance with the NTTG's Transmission Providers' Attachment K that included FERC Order 1000 regional and interregional transmission planning requirements[8]. The dRTP is a result of reliability and economic studies and activities outlined in the NTTG Biennial Study Plan for the 2016-17 Regional Planning Cycle[9] and carried out by the NTTG Technical Work Group[10]. The planning

[8] Link to Full Funder Attachment Ks

[9] Link to the Approved 2016-2017 NTTG Study Plan

[10] This work group was established by the NTTG Planning Committee chair to create the study plan and perform the technical evaluations necessary to develop the Regional Transmission Plan. The TWG is comprised of the NTTG Planning Committee or

process started by developing the Initial Regional Transmission Plan through a bottom up approach by aggregating the Funding Transmission Providers' (TPs') local transmission plans into a single regional transmission plan. Next the IRTP non-Committed projects within the NTTG geographical area were analyzed through Change Case plans to determine whether there were Alternative Projects that would yield a regional transmission plan that would be more efficient or cost effective than the IRTP. It is the result of this analysis that formulated the dRTP presented herein. This dRTP document discusses in detail the activities and studies completed and how the dRTP was developed.

# III. Study Methodology

To determine the most efficient or cost-effective transmission plan that would become the dRTP, both reliability and economic studies were performed in accordance with the 2016-2017 Study Plan. The reliability studies utilized production cost modeling and power flow studies. The economic studies utilized the Attachment K's three metrics (i.e., capital-related costs, energy losses, and reserves) to analyze those Change Case plans that were reliable to further determine the cost effectiveness of the NTTG transmission plan. The reliability study process and the economic evaluations will be described in more detail below.

## A. Production-Cost Modeling

Gridview[11] production cost software was used to look at 8760 hours of data to determine stressed conditions within the NTTG footprint. The production cost dataset representing the year 2026 was obtained from the Transmission Expansion Planning Policy Committee ("TEPPC") of the Western Electricity Coordinating Council ("WECC"). This case included a representation of the load, generation and transmission topology of the WECC interconnection-wide transmission system ten years into the future. The TEPPC dataset was released on July 1st. Members of the TWG reviewed the loads, resources, and transmission data for their transmission planning area to ensure that the representations in this case were reasonably close to the data they had submitted in the first quarter ("Q1") of the biennial cycle. TWG identified the need to incorporate a significant number of corrections prior to use by NTTG. In early September NTTG shared these changes with the other Regional Planning entities and WECC for



their representatives who have access to and expertise in power system power flow analysis or production cost modeling, are committed to participating in the entirety of the planning process (not just a single study or phase), and will ensure completion of those assignments in a cooperative and timely manner.

[11] Gridview is a registered ABB product

inclusion in their future studies. The TWG then agreed to use this case in creating the stressed cases discussed below.

TWG determined that there were seven stressed conditions which impact the NTTG area that should be studied:

- high NTTG summer peak;
- high NTTG winter peak;
- high Montana-Northwest (Path 8) flows;
- high southern Idaho import (Idaho-Northwest Eastbound);
- high southern Idaho-Northwest export(Idaho-Northwest westbound);
- high NE-SE (Path Tot2) flows; and
- high Wyoming Wind scenario.

After running all 8760 hours using the GridView production-cost program, the data was analyzed and the hours representative of the seven stressed conditions were identified. The hours are shown in Table 2 below.

| Stressed Condition | Date | Hour | TWG Label |
|---|---|---|---|
| **Max. NTTG Summer Peak** | July 22, 2026 | 16:00 | A |
| **Max. NTTG Winter Peak** | December 8, 2026 | 19:00 | B |
| **Max. MT to NW** | September 10, 2026 | Midnight | C |
| **High Southern Idaho Import** | June 11,2026 | 14:00 | D1 |
| **High Southern Idaho Export** | September 17, 2026 | 2:00 | D2 |
| **High Tot2 Flows** | November 11, 2026 | 17:00 | E |
| **High Wyoming Wind** | September 17, 2026 | 2:00 | F |

**Table 1 – Hours Selected from 2026 WECC TEPPC Case to Represent Different NTTG System Stresses**

## B. Power Flow Cases

The next step in the process was developing the power flow stressed condition cases by converting (i.e., a "round-trip process") the production cost model for the above seven hours into the Power World power flow cases. Even though the TWG has used a conversion process (i.e., export the production cost database to a power flow readable format) for the past four cycles, this process continues to require effort to manipulate the resultant power flow base cases so the power flow model will run. It should be noted that this conversion process has improved with each cycle from months to weeks to now hours once the initial dataset has been adjusted.

The TWG determined that power flow model loads extracted from the production cost model did not stress the transmission system as much as historical conditions would suggest. Further exploration found that the production cost database uses a 1 in 2 load forecast for its basis and when extracting a single hour from the production cost model to the power flow model this single hour may not represent a coincident peak hours between the balancing areas as has been experienced in the past. TWG recognized that these differences result in a lower than expected peak loads in the extracted power flow for a number of the balancing areas within NTTG. To better reflect expected stressed conditions for the selected peak loads within the NTTG footprint, the balancing area loads were adjusted to get peak loads that represent 1 in 5 to 1 in 10 peak load conditions. Each of the stressed cases were then reviewed by the TWG to ensure that the case met steady state system performance criteria (no voltage issues or thermal overloads). Bubble diagrams showing the inter-area flows for each of the stressed cases are included in the results sections below.

The TWG is in the process of developing dynamic data and contingency files to be applied to a selected number of the power flow contingency cases. This work will continue into Q5 of the study cycle and the results will be published in the Draft Final Regional Transmission Plan that is produced by the end of Quarter 6 and presented to stakeholders for comment in Quarter 7.

## C. System Performance Criteria

The details of the system performance criteria can be found in the study plan (see footnote 3). An abbreviated summary of the NERC reliability criteria state that lines and transformers must not exceed their normal and emergency thermal ratings and bus voltages must remain within certain ranges. For steady-state conditions the voltages must be between 95% and 105% for busses less than and including 345 kV and between 100% and 110% for 500 kV buses and above. Post contingency voltages must be > 90% and < 110% for 345 kV and below and between 95% and 115% for 500 kV and above.

For dynamic studies, the criteria is based on TPL-001-WECC-CRT-3, following fault clearing, the voltage shall recover to 80% of the pre-contingency voltage within 20 seconds for each BES bus serving load and shall not dip below 70% for more than 30 cycles nor remain below 80% for more than 2 seconds once the voltage has recovered above 80% post fault. All oscillations shall be positively damped within 30 seconds or the contingency will be considered unstable.

# IV. Stress Conditioned Case Study Results

After analyzing the steady-state performance of each of the seven stressed conditioned cases, a rigorous contingency analysis commenced. This contingency analysis consisted of over 375 single contingencies and 39 credible double contingencies, to determine if each contingency meets the system performance criteria. If there were reported reliability violations by the power flow program, TWG determined if these violations were legitimate and needed mitigation to correct the violation or if modeling problems (e.g., corrections to the modeled contingency actions) caused the reliability violation. For the legitimate violations, TWG determined what additional facilities would be needed to meet the criteria and adjust the IRTP to include the additional facilities. If no violations, then the facilities in the IRTP are deemed adequate for serving the NTTG loads and resources in the year 2026. The results of each of the seven stressed cases are discussed below:

## A. NTTG Summer Peak Case

This case has an NTTG summer peak load of 24,100 MW with 17,851 MW of generation. The sum of the NTTG boundary flows in the case is approximated by taking the difference between generation and load, which equated to -6,250 MW (import). A bubble diagram of the case is shown below.

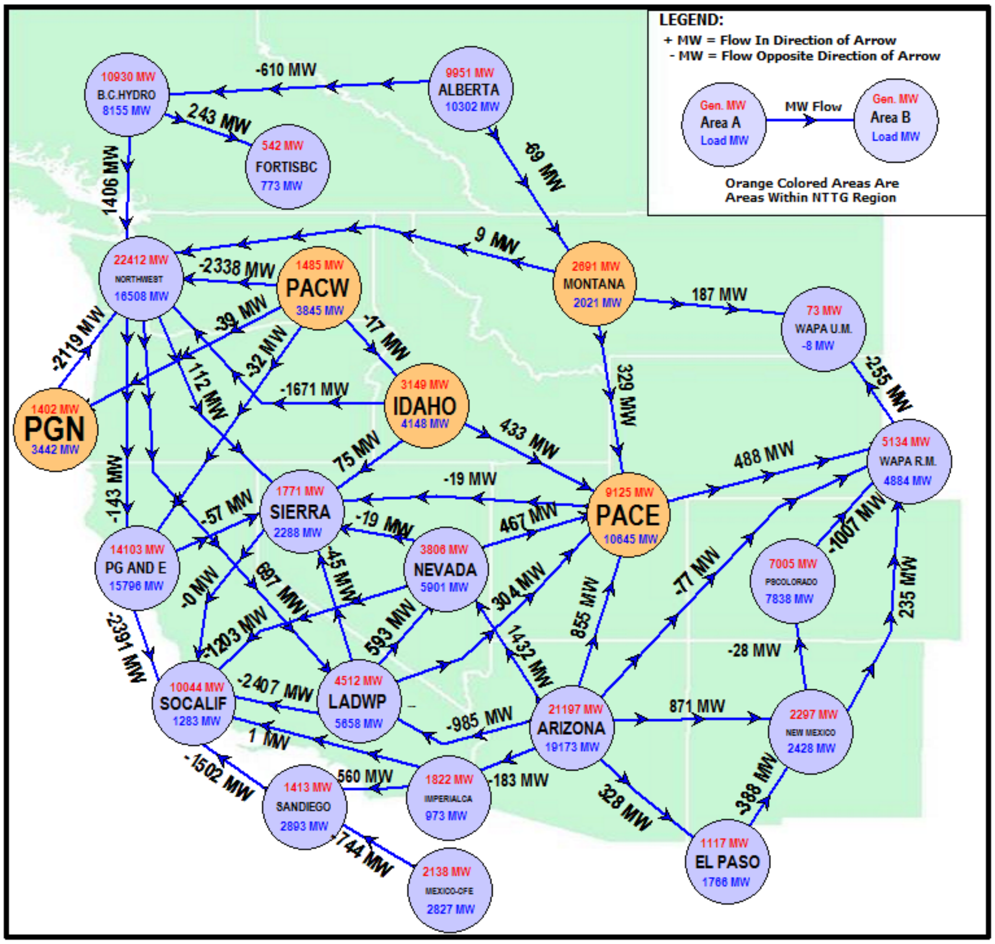



**Figure 2 - Tie-line flows for Summer Peak Case**
**(July 22, 2026 Hour 16 - NTTG Case A)**

In this case, the IRTP performed reasonably well with a few local areas with known existing issues that have not risen to the level of justifying expenditures to resolve them. The Null Change Case indicates, although to a lesser extent than the other flow conditions, that system performance is inadequate without transmission system additions by 2026 to meet NTTG's requirements.

## B. NTTG Winter Peak Case

The NTTG winter peak load in this case is 22,468 MW with a total of 19,261 MW of generation. The difference of generation and load approximates the boundary flow which is equal to -3,208 MW (import). A few local system violations occur in the IRTP case. It is apparent that the heavy winter condition is less stressful than the heavy summer condition, as very few additional violations occur in the Null case compared to the IRTP case.

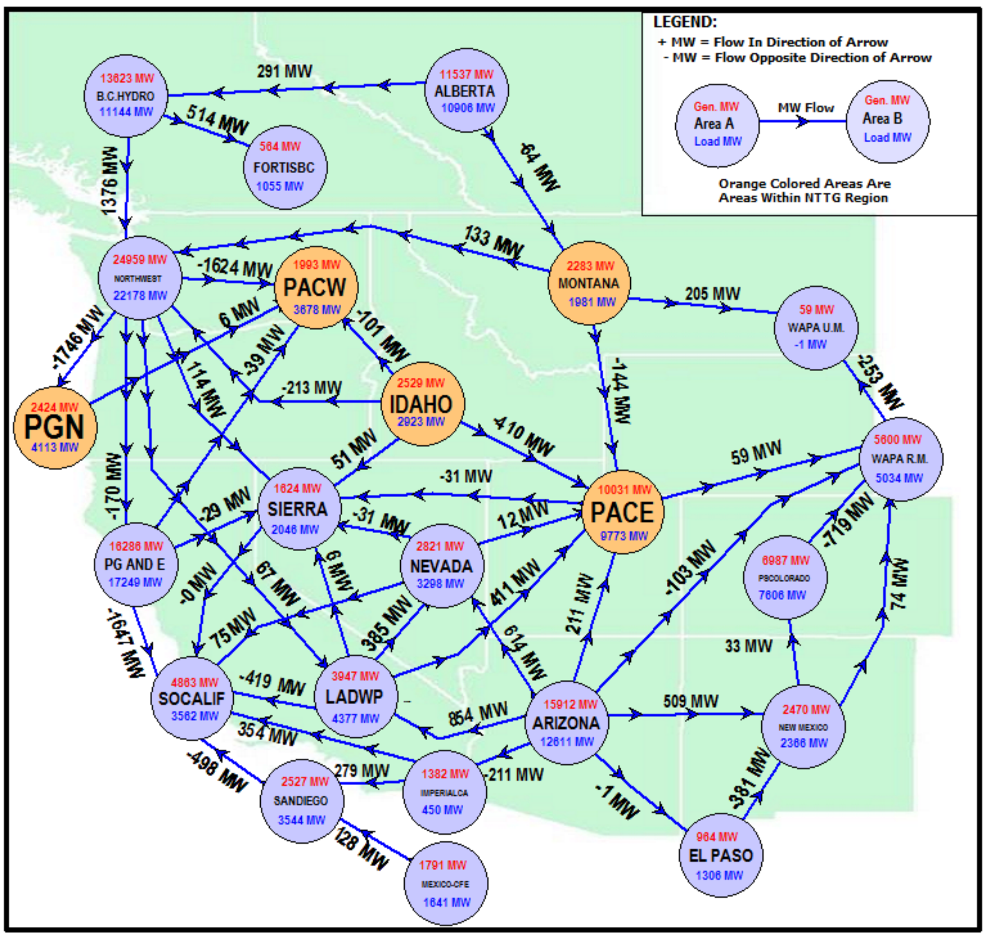



**Figure 3 - Tie-line flows for Winter Peak Case**
**(Dec 8, 2026 Hour 19 - NTTG Case B)**

## C. Maximum Path 8 Case

This case has a Path 8 flow of 2,042 MW. The NTTG total is approximately 959 MW import. The NTTG load and generation in this case are 13,097 MW and 12,138 MW respectively. The bubble diagram follows. This case is planned to be used for the Public Policy Consideration study to be performed in Q5, no reliability studies have been performed on it yet.

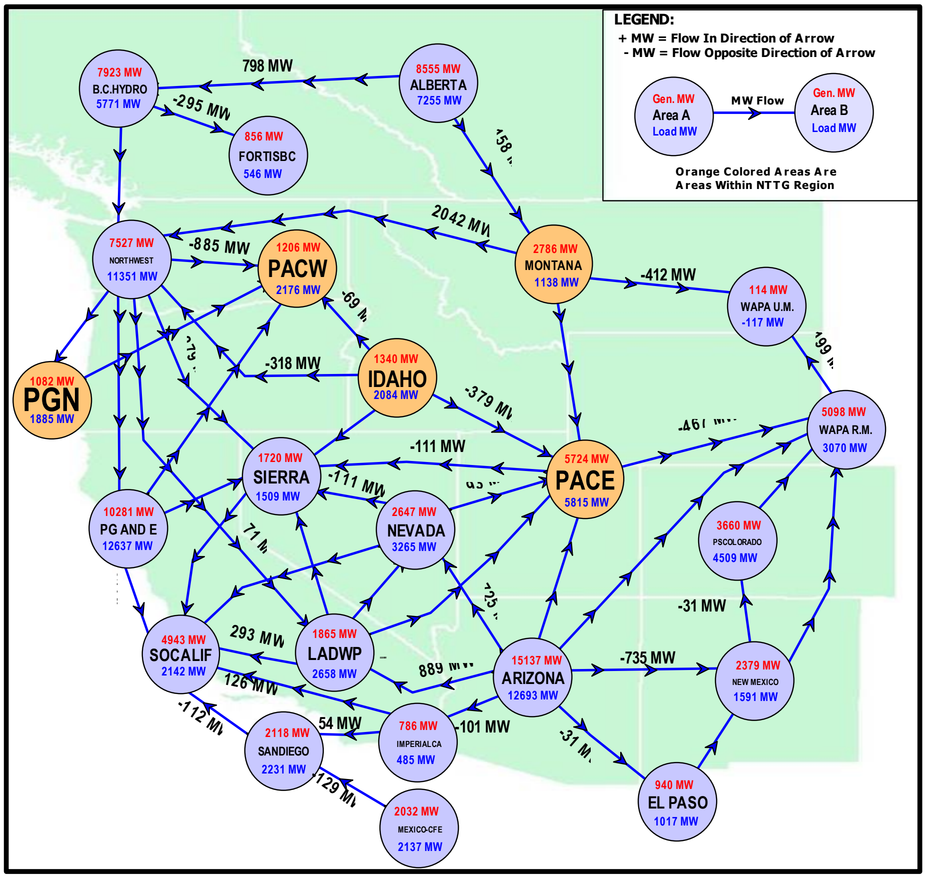



**Figure 4 - Tie-line flows for Montana-Northwest Case**
**(Sept 10, 2026 Hour 24 - NTTG Case C)**

## D1. High Southern Idaho Import Case

This case has the ID-NW Path flow at -2,244 MW. The NTTG load and generation in this case are 16,382 MW and 9,159 MW respectively, the NTTG footprint is importing 7,223 MW. The bubble diagram follows. The IRTP performs well with a few local violations. The Null case is another matter, as it is clear that the existing system topology is incapable of importing power to this level and load service obligations in southern Idaho would not be met.

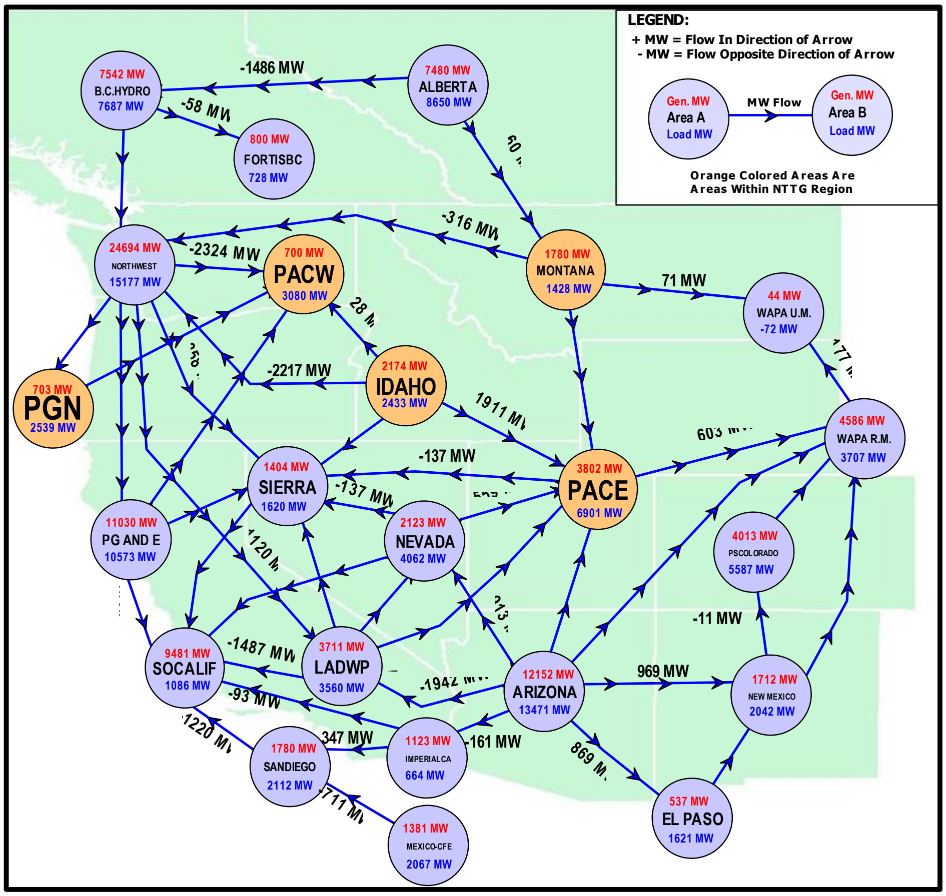



**Figure 5 - Tie-line flows for High Southern Idaho Import Case**
**(June 11, 2026 Hour 14 - NTTG Case D1)**

## D2. High Southern Idaho Export Case

This case has the ID-NW Path 8 flow at 3,391 MW. The NTTG load and generation in this case are 11,935 MW and 14,683 MW respectively, with NTTG exporting 2,748 MW. Similar to the D1 flow condition, the IRTP performs well with just one contingency that causes a series cap bank to overload, that bank has reached the end of its useful life and is likely to be replaced before 2026. The bank rating will be reviewed prior to its replacement to insure it does not inhibit transfers across the system. The Null case again demonstrated that without reinforcement, the system would not be able to support the expected transfers and would not satisfy NTTG's requirements for 2026.

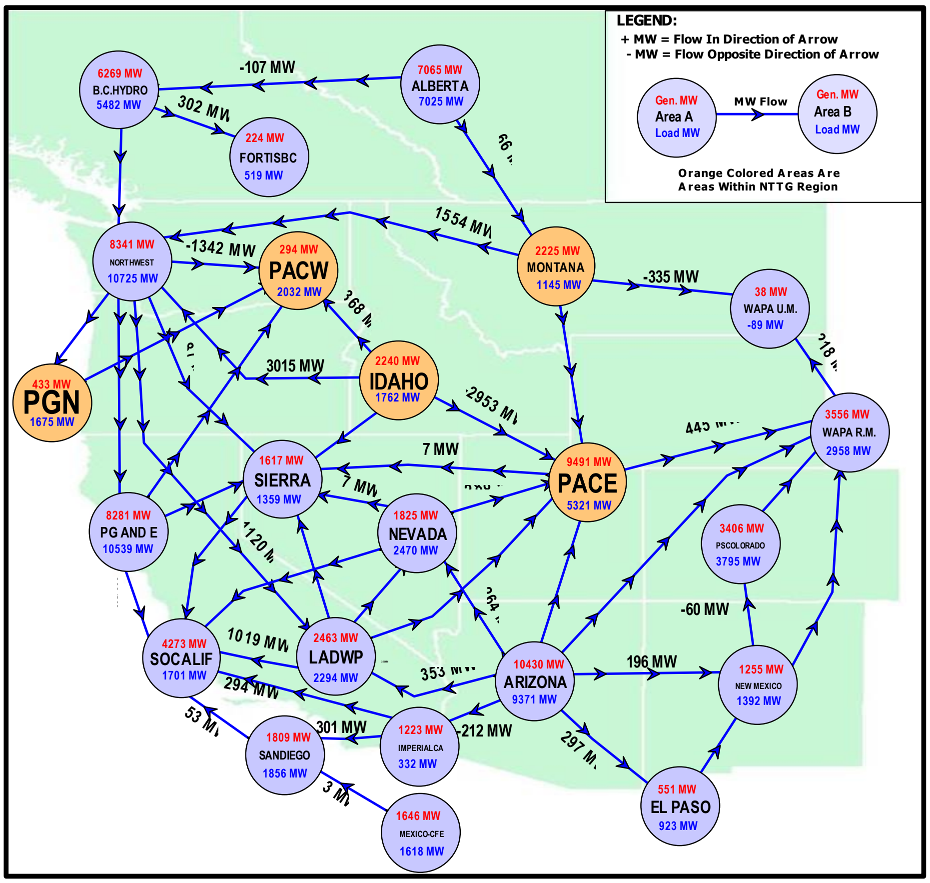



**Figure 6 - Tie-line flows for High Southern Idaho Export Case**
**(Sept 17, 2026 Hour 2 - NTTG Case D2)**

## E. High Tot2 Case

This case has a Tot2 flow of 1,566 MW. The NTTG load and generation are 16,625 MW and 16,620 MW respectively, with the NTTG footprint nearly balanced with a 5 MW import. The bubble diagram follows. The main focus of the selection of this case is to evaluate the performance of the ITPs in supporting interregional transfers. These transfers did not satisfy of defer NTTG's 2026 footprint requirements.

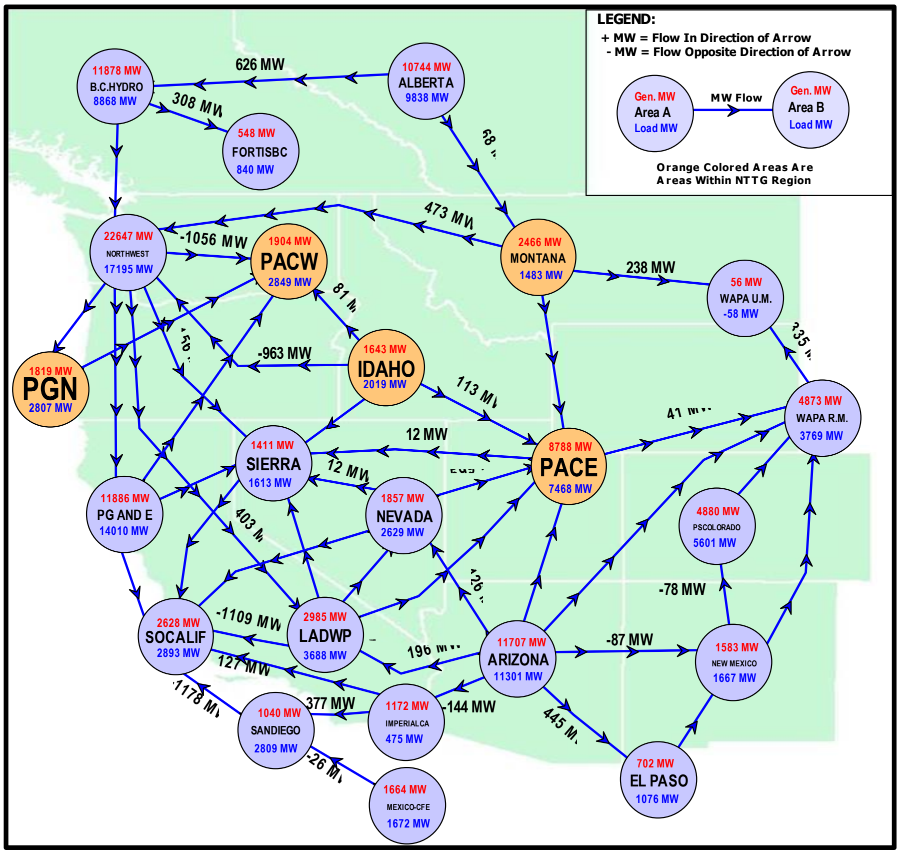



**Figure 7 - Tie-line flows for High Tot2 Case**
**(Nov 11, 2026 Hour 17 - NTTG Case E)**

## F. High Wyoming Wind Case

The NTTG load and generation in this case are 11,935 MW and 15,015 MW respectively with a NTTG export of 3,081 MW. The Wyoming wind was increased from 630 MW to 1,303 MW. The bubble diagram follows. This case was developed from the D2 case by adjusting the production level of the planned Wyoming wind generation. The main focus was to check the performance of the Wyoming system to support this level of resource. With the additional transfers across southern Idaho, the pRTP performed poorly and failed to meet NTTG's footprint requirements. Adding a number of Gateway West segments not included in the pRTP, resolved the performance issues. The prior planning cycle failed to study this level of transfer across southern Idaho.

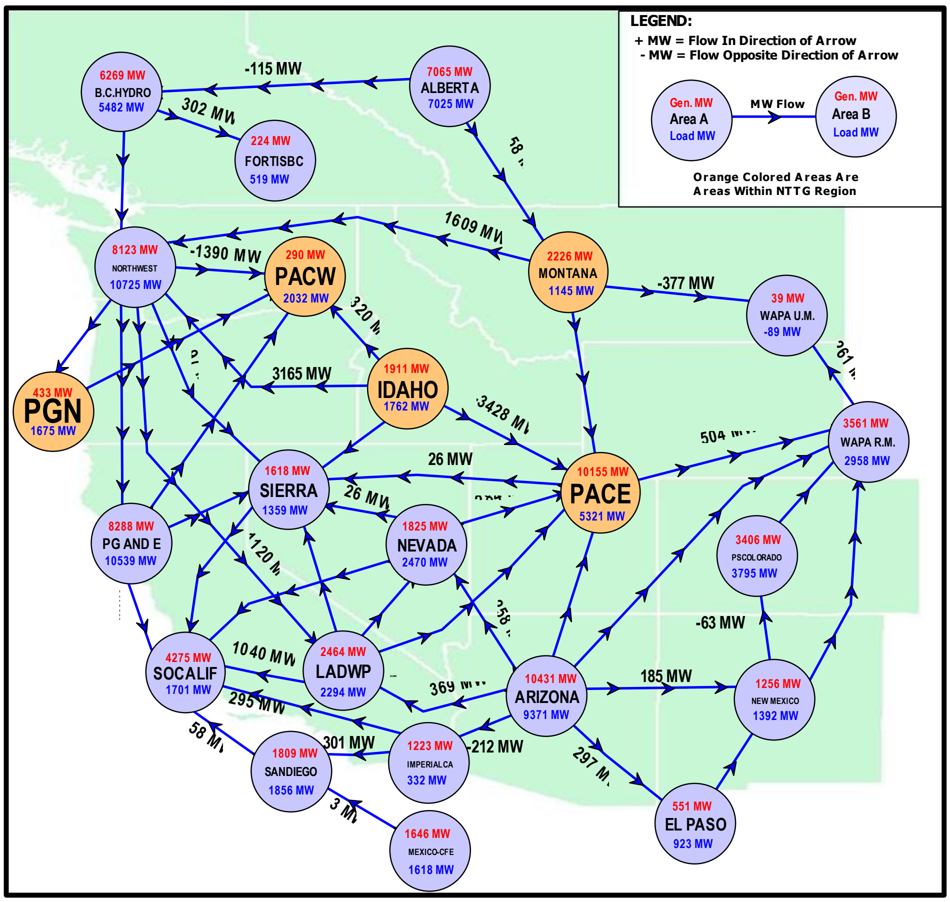



**Figure 8 - Tie-line flows for High Wyoming Wind Case**
**(Sept 17, 2026 Hour 2 - NTTG Case F)**

# V. Change Case Results

For each of these stress conditioned cases, a "Null" Change Case was prepared and reliability results were analyzed. The Null case represents roughly today's transmission topology with 2026 Loads and Resource requirements. Only the Heavy Winter case (B) had acceptable performance. All the other conditions had performance issues that require correction, in increasing order; the Heavy Summer case (A), the High Tot2 case (E), the B2H import case (D1), the Heavy Export case (D2) and finally the High Wyoming wind case (F) being the worst.

The IRTP as submitted in quarter 1 has several non-Committed projects, as shown below these include:

- The Boardman to Hemingway Project (Longhorn-Hemingway)
- The Gateway West Project which contains a number of sub-sections:
    - Windstar-Aeolus 230 kV
    - Aeolus-Anticline (Jim Bridger) 500 kV
    - Anticline-Populus 500 kV
    - Populus-Borah 500 kV
    - Populus- Cedar Hill 500 kV
    - Cedar Hill-Hemingway 500 kV
    - Cedar Hill- Midpoint 500 kV
    - Borah-Midpoint 345 to 500 kV conversion
    - Midpoint-Hemingway #2 500 kV
- The Gateway South Project:
    - Aeolus-Clover 500 kV
- The Antelope Projects:
    - Goshen-Antelope 345 kV
    - Antelope-Borah 345 kV

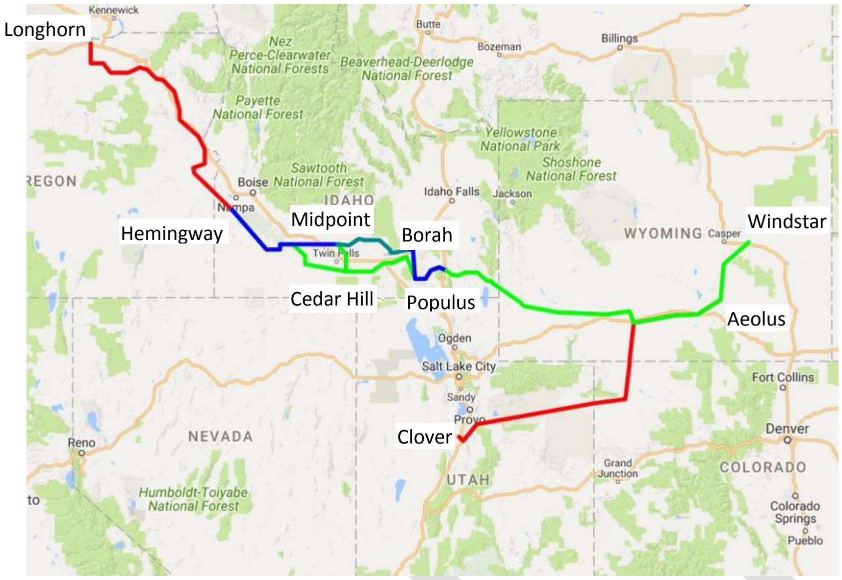



Figure 9 - IRTP Projects

The prior Regional Transmission Plan from last planning cycle is a subset of the projects submitted in Quarter 1:

- The Boardman to Hemingway Project (Longhorn-Hemingway)
- The Gateway West Project which contains a number of sub-sections:
  - Windstar-Aeolus 230 kV
  - Aeolus-Anticline (Jim Bridger) 500 kV
  - Anticline-Populus 500 kV
- The Gateway South Project:
  - Aeolus-Clover 500 kV

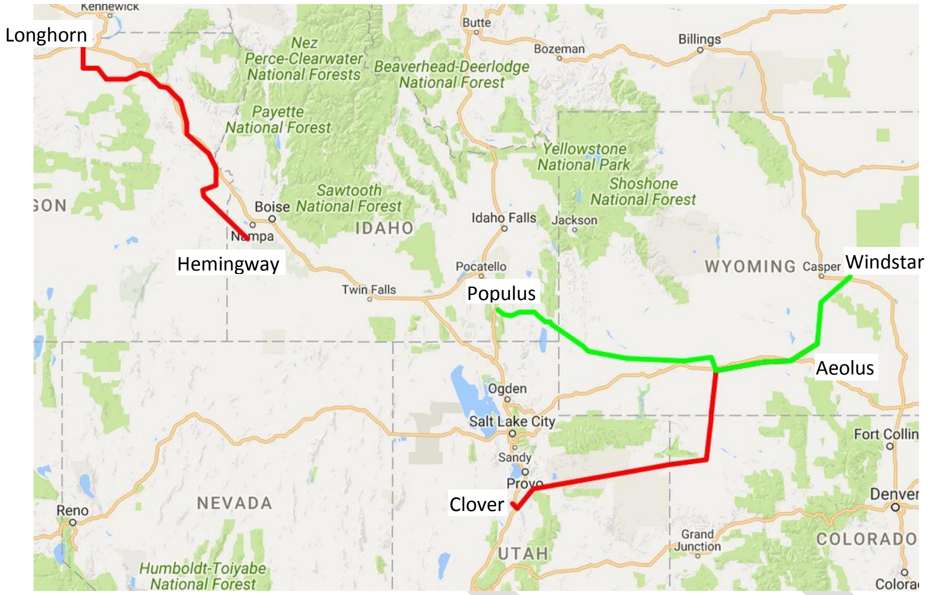



Figure 10 - pRTP Projects

In order to efficiently study the wide range of potential combinations of non- Committed projects, the TWG formulated a Change Case matrix included an example in the Biennial Study Plan[12]. Once the power flow cases had been selected and developed, the TWG modified the matrix to better reflect the recommended analysis. During the month of October, 2016, stakeholder comments were solicited on the draft set of projects selected for analysis in the Change Case matrix. No comments were submitted. The matrix was also presented to the Planning Committee at the October and November meetings. Below is the change case matrix that was used by the TWG:



[12] The Biennial Study Plan is the study plan used to produce the Regional Transmission Plan, as approved by the NTTG Steering Committee.

| Case | B2H* | Gateway S* | Gateway W* | Antelope Projects | SWIP N | Cross-Tie | TWE | Case(s): |
|---|---|---|---|---|---|---|---|---|
| null | | | | | | | | A B D1 D2 F |
| pRTP | X | X | D | | | | | A B D1 D2 F |
| iRTP | X | X | X | X | | | | A B D1 D2 F |
| CC1 | X | | | | | | | A B D1 D2 F |
| CC2 | | X | | X | | | | A D2 E F |
| CC3 | | X | X | | | | | A D2 E F |
| CC4 | X | | X | X | | | | A D1 D2 E F |
| CC5 | | | | | | | X | A B D1 D2 F |
| CC6 | | | | | | X | | A B D1 D2 F |
| CC7 | | | | | X | | | A B D1 D2 F |
| CC8 | | | | | | | X | E+RPS |
| CC9 | | X | | | | | X | E+RPS |
| CC20 | | X | X | | | | X | E+RPS |
| CC10 | | | | | | X | | E+RPS |
| CC11 | | X | | | | X | | E+RPS |
| CC18 | | X | X | | | X | | E+RPS |
| CC12 | | | | | X | | | E+RPS |
| CC13 | | | X | | X | | | E+RPS |
| CC19 | | X | X | | X | | | E+RPS |
| CC14 | | X | X | | X | X | | E+RPS |
| CC15 | | | X | | X | | X | E+RPS |
| CC16 | | X | | | | X | X | E+RPS |
| CC17 | | X | X | | X | X | X | E+RPS |
| CC21 | X | X | A | X | | | | D2 F |
| CC22 | X | X | B | X | | | | D2 F |
| CC23 | X | X | C | X | | | | F |

* B2H and Alternate P in the pRTP are similar to B2H, Gateway S and Gateway W in the 2016-17 Q1 data submittals

| | |
|---|---|
| A | iRTP without Midpoint-Hemingway #2 and Cedar Hill-Midpoint |
| B | iRTP without Borah-Midpoint Uprate and Populus-Borah |
| C | iRTP without Midpoint-Hemingway #2, Cedar Hill-Midpoint and Populus-Borah |
| D | iRTP without Midpoint-Hemingway #2, Cedar Hill-Midpoint, Populus-Cedar Hill-Hemingway, Populus-Borah and Midpoint-Borah Uprate |
| | The change case was run with and without B2H |

Table 2 - Change Case matrix used in the development of this report

In all, over 100 reliability studies were performed with the previously mentioned 410+ contingencies. A summary of the performance of these cases is described below. In order to better communicate the results of these studies, the TWG created heat maps which present a weighted[13] graphical performance of a change case on a specific flow condition. In these heat maps, performance issues were accumulated for each powerflow zone, for example, the D2a-Null case performance looks like:

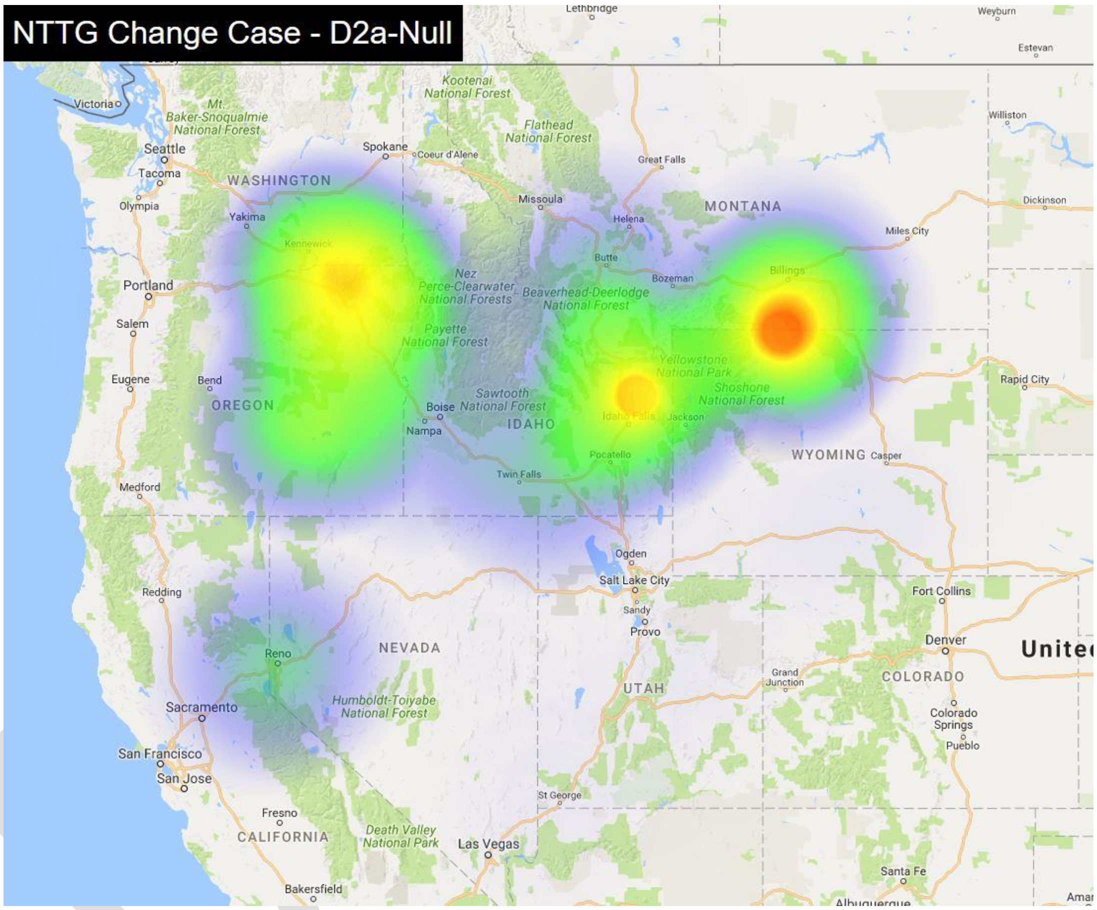



Figure 11 – Example Heat Map of the D2-Null Case

This map does not indicate where the contingency occurred but the general location where the performance (e.g., overloaded transmission line) issues occurred for the contingency which may

[13] High voltage conditions had a weighting of 1; Low voltage conditions had a weighting of 3; and overloads of branches had a weighting of 5. For example, a zone with 10 contingencies that caused an overload of one branch would receive a count of 50, which would then be translated into a color on the map. A blue color represents a weighted total of about 10, green is a count up to 30, yellow is a count up to 50 and red is for a weighted count exceeding about 70.

be 300 or 400 miles away. In the above heat diagram the accumulation of overloads and voltage issues are represented by the various colors. The map show three general areas of reliability violations – NW Wyoming/SE Montana, southern Idaho and SE Washington/Central Oregon. These violations are occurring because the transmission systems are incapable of handling anticipated transfers across that area's transmission system.

The same map for the D2-IRTP case looks like:

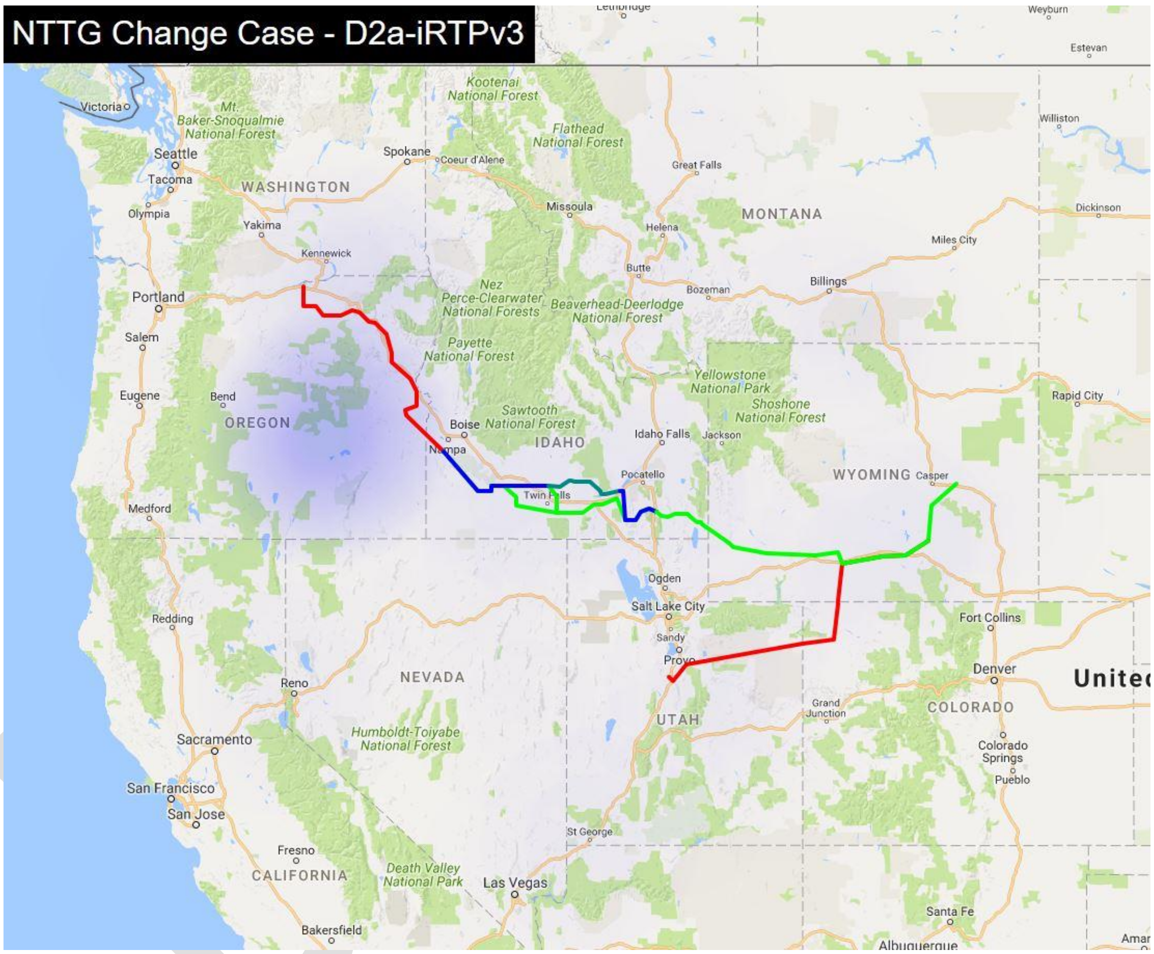



Figure 12 – Heat Map of the D2 Case with the IRTP facilities included

In this case, the map points to an overload in Oregon area on the Burns Series capacitor that is likely to be replaced prior to 2026. The rating of the bank will be revaluated to avoid it becoming a bottleneck to system performance. This map shows the dramatic improvement of the IRTP Change Case has when compared to the Null case.

## A. Heavy Southern Idaho Import Case results

Similarly, comparing the Heavy Import Null Case (D1-Null) with a case where the B2H project (inserted as a red line in the right heat map) is added is shown below:

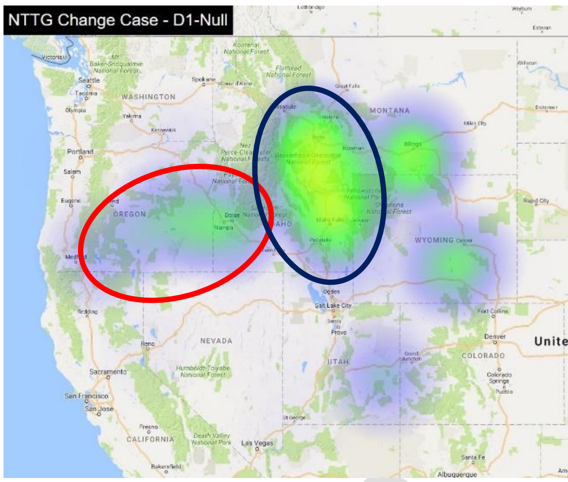



Figure 13

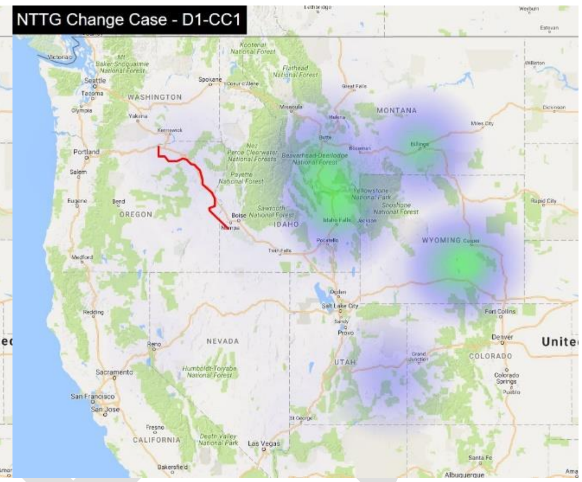



Figure 14

The stress across the Idaho-Northwest path, shown within the red oval, has been relieved when B2H is added, as well as, stress across the Montana-Idaho path (WECC Path 18), shown in the blue oval. The heat map Figure 14 on the right still has issues along the Continental Divide that demonstrates B2H does not resolve all the performance problems for the D1 case. Including the other non-Committed projects (Gateway West and Gateway South transmission lines shown in the blue oval) with the B2H project to the D1 flow condition, the violations in Figure 14 are eliminated.

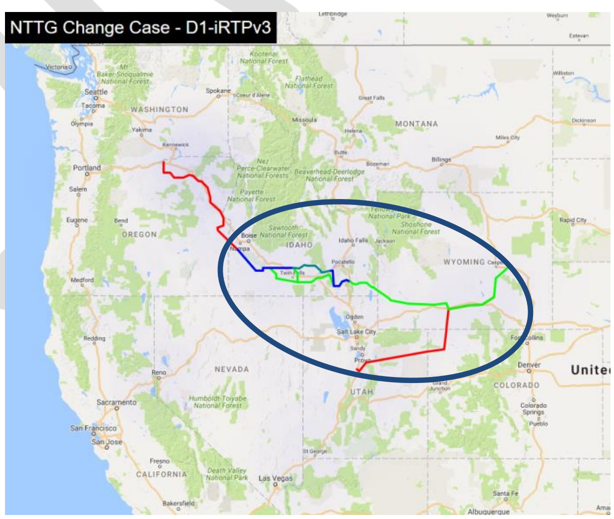
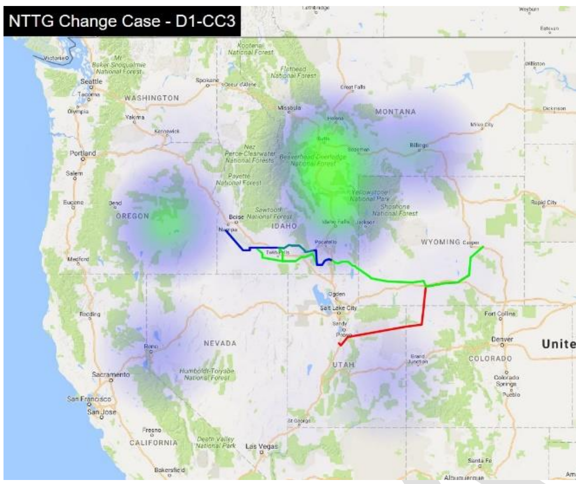



Figure 15

Change Case CC3, in the heat map Figure 16 below, tests to see if the Gateway West and/or Gateway South projects shown in the blue oval above can replace or be comparable to the B2H project. As can be seen below, a number of performance issues without the B2H project included in the D1-Null case have not been alleviated. The Figure 17 heat map shows that NTTG's prior Regional Transmission Plan (pRTP[14]) proposed non-Committed transmission facilities do not alleviate the violations.



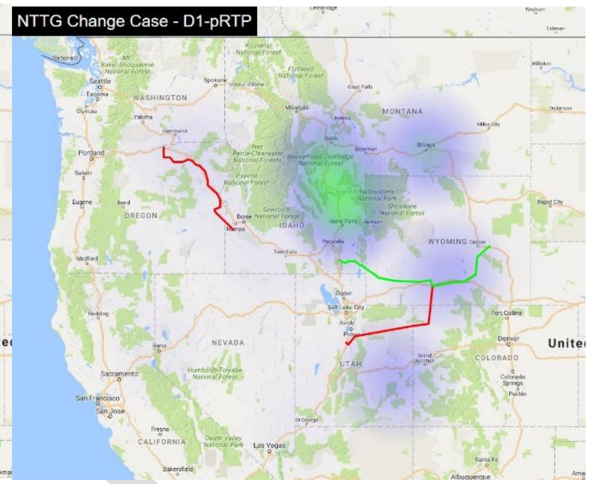




Figure 16 Figure 17



[14] The pRTP excludes the western portion of the Gateway west project west of the Populus substation in eastern Idaho.

## B. Heavy Southern Idaho Export Case results

The D2-Null case is shown again in Figure 18 to compare the performance improvement of adding the B2H project. As can be seen in Figure 19, again the stress across the Idaho-Northwest cutplane is relieved, but significant issues remain east of Hemingway.

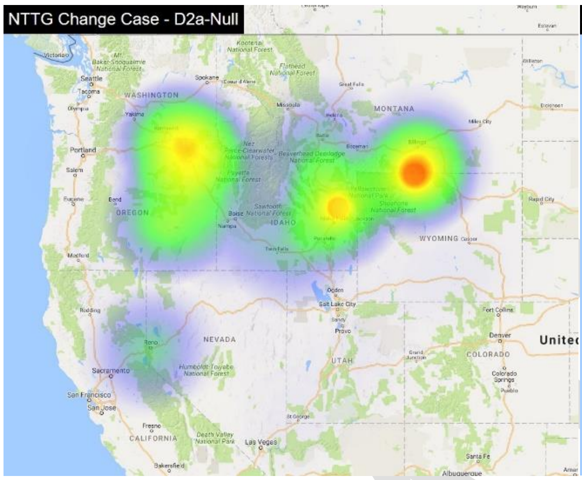



Figure 18

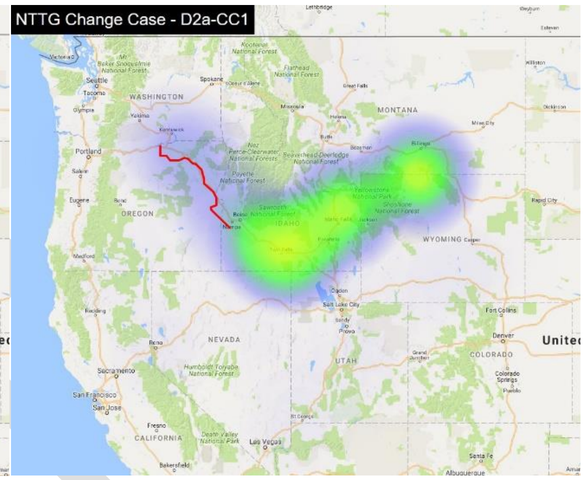



Figure 19

## C. High Wyoming Wind Case results

The F-Null case in Figure 20, it indicates that its performance is worse than the heavy southern Idaho export case. When the IRTP facilities are added in Figure 21, the only remaining problems is with the rating of the Burns series capacitor bank. This bank is due for replacement since it has reached the end of its use full life. Its future rating has not been determined but the parties will consider these studies in establishing its new rating.

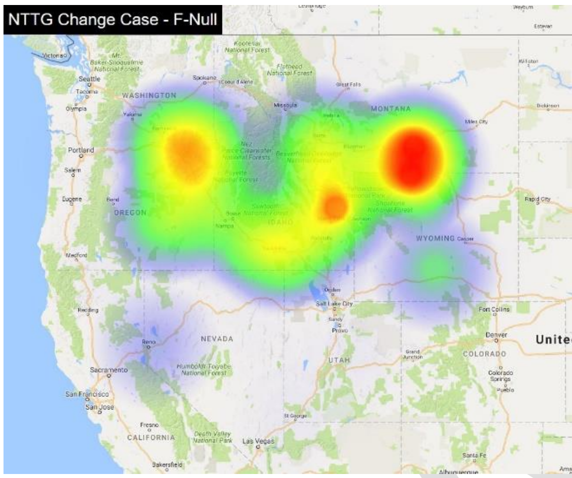



Figure 20

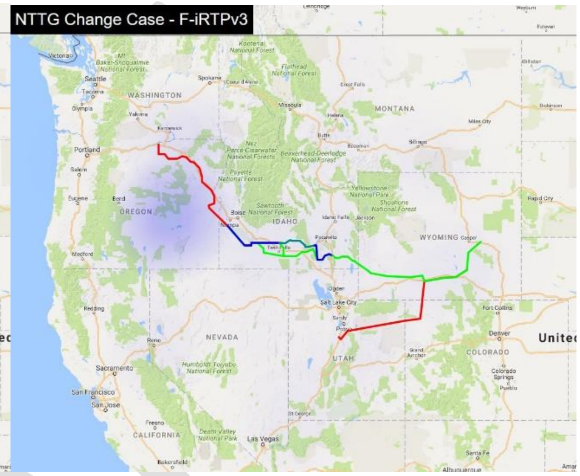



Figure 21

The prior Region Transmission Plan does not perform as well as the IRTP, if fact it missed a significant issue related to the transfers across the eastern portion of southern Idaho.

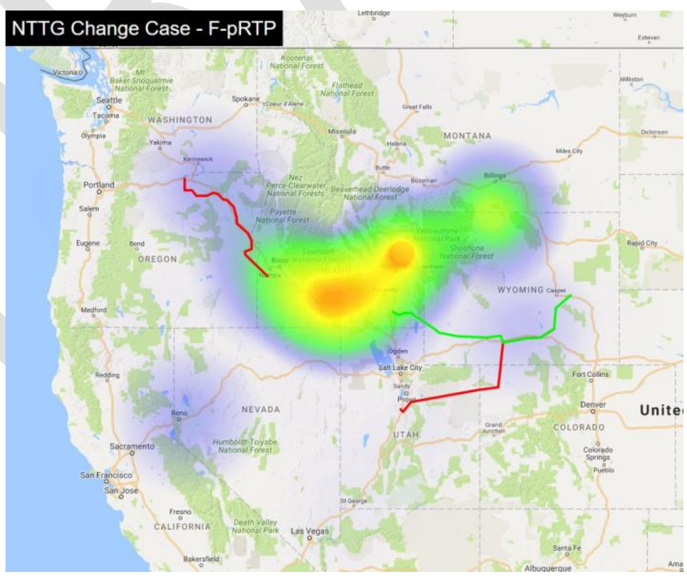



Figure 22

## D. Interregional Transmission Projects

The Interregional Transmission Projects were analyzed to determine whether an ITP alone or in combination with the other ITPs and/or the non-Committed projects could, from a regional perspective, satisfy NTTG's transmission needs on a regional or interregional basis more efficiently or cost effectively than through local planning processes. The ITPs were added to the Null cases without any additional resources to serve NTTG load beyond those resources identified for ITP's use to serve California RPS needs. The heavy southern Idaho export case results are shown graphically below in Figures 23 through 26.

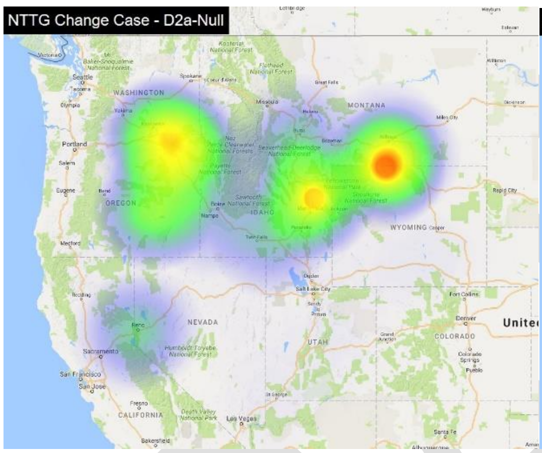



Figure 23

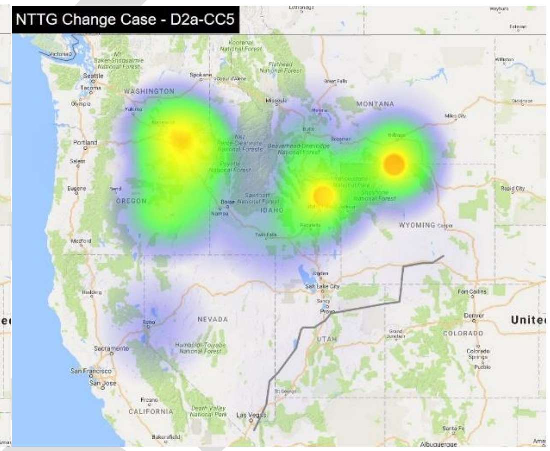



Figure 24

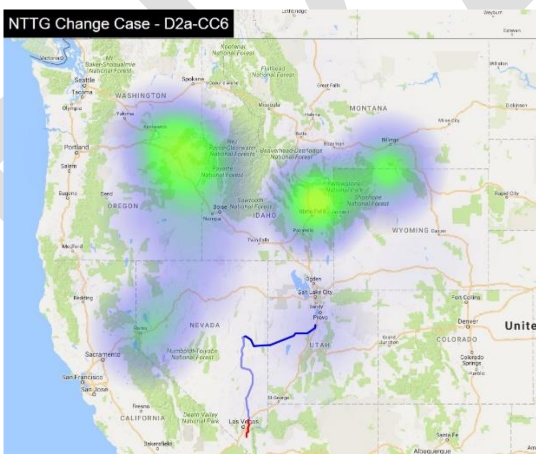



Figure 25

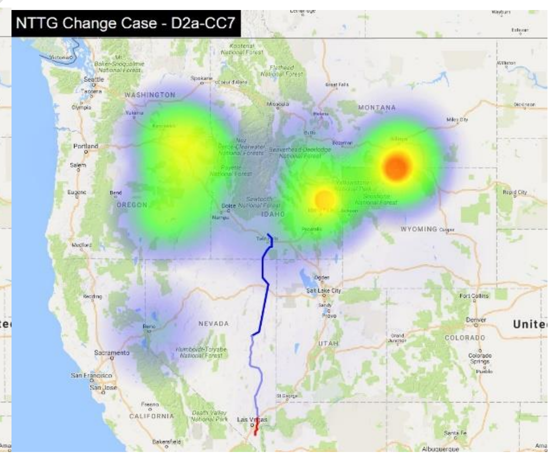



Figure 26

For the High Wyoming Wind case:

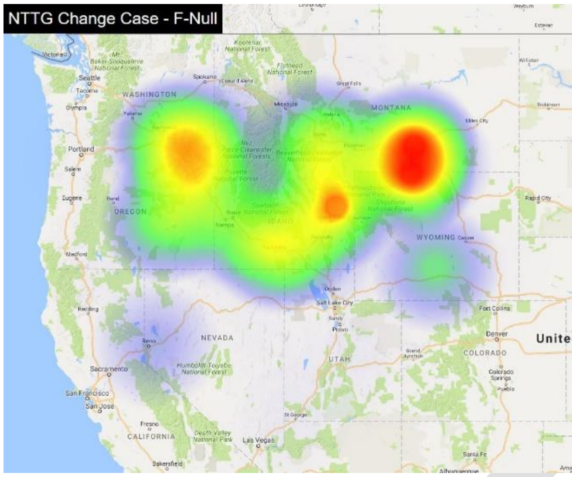



Figure 27

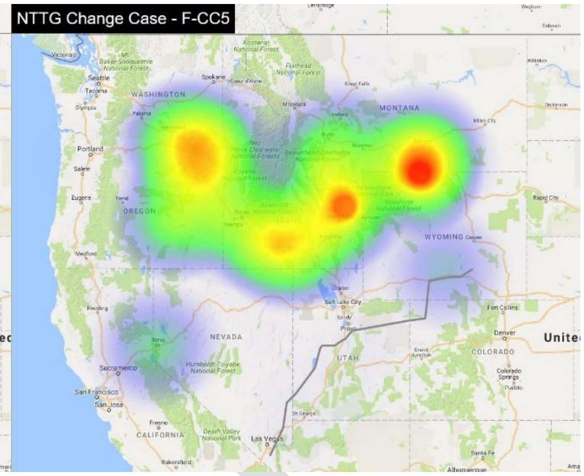



Figure 28

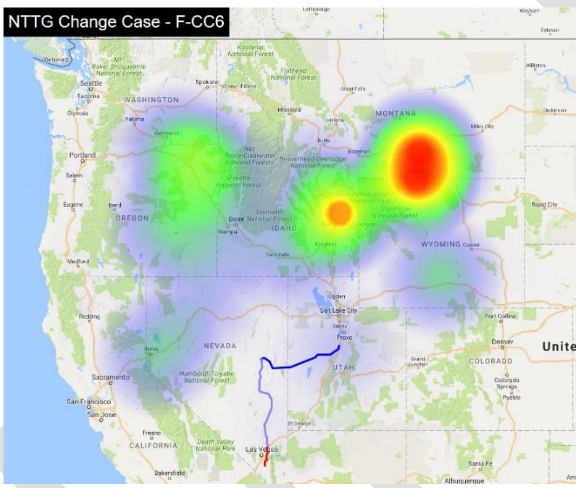



Figure 29

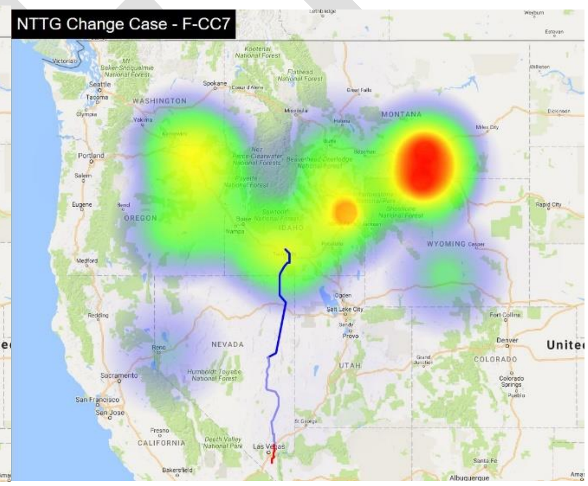



Figure 30

It does not appear that the ITPs provide the NTTG footprint with regional benefits by significantly reducing performance issues or displacing NTTG non-Committed projects.

The IRTP was also analyzed to determine whether it is capable of supporting the interregional resource transfers proposed by the ITPs:

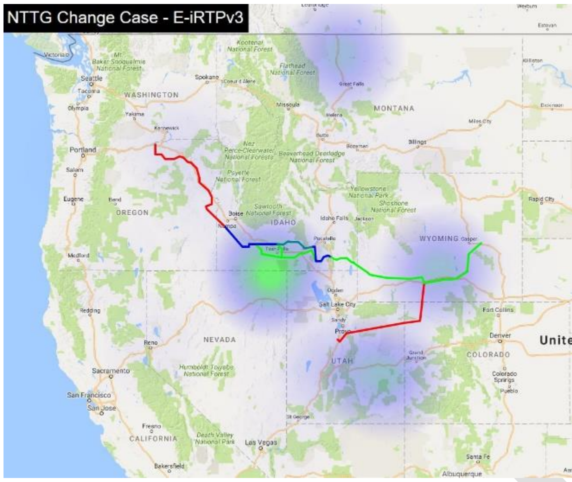



Figure 31

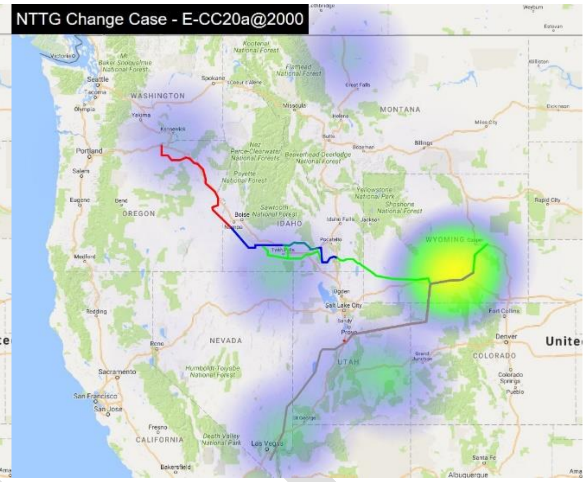



Figure 32

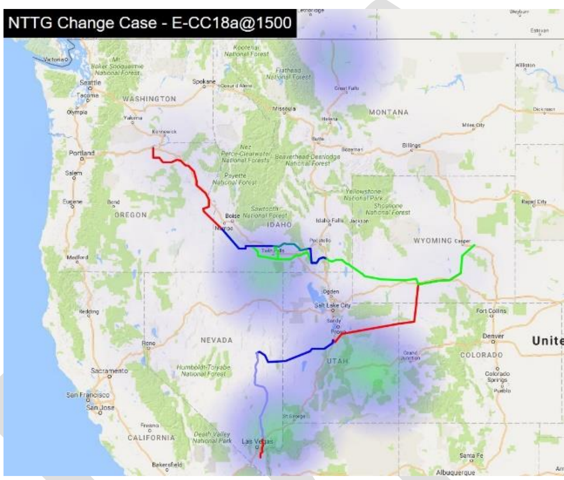



Figure 33

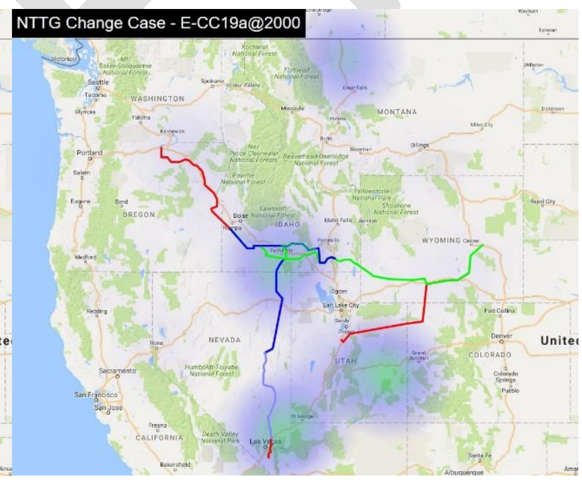



Figure 34

Each of the ITPs interfaces with the additional wind resources in Wyoming differently. In the TWE E-CC20a case (Figure 32), the case was run just tripping the wind resource and not tripping the balancing combustion turbine resources for DC line outages. In order to avoid performance issues, the entire 2,000 MW would need to be tripped. Additionally, the DC terminal was modeled just connecting to the existing 230 kV system, even when the Gateway West and South 500 kV projects were represented in the case. Adding a 500 kV interface to the DC terminal would eliminate the Wyoming performance issue.

Combinations of the ITPs projects was also studied with resource additions up to 5,500 MW.

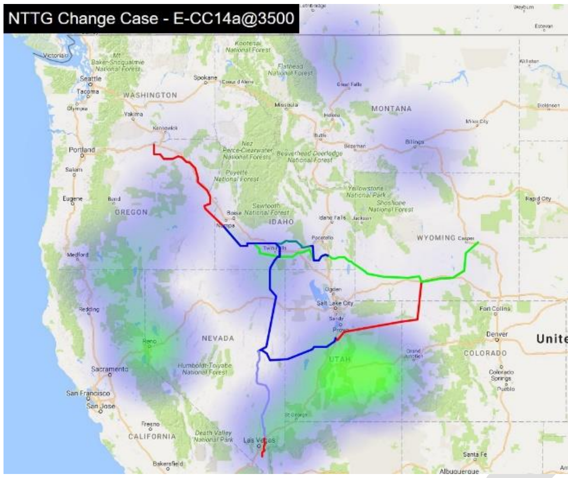



Figure 35

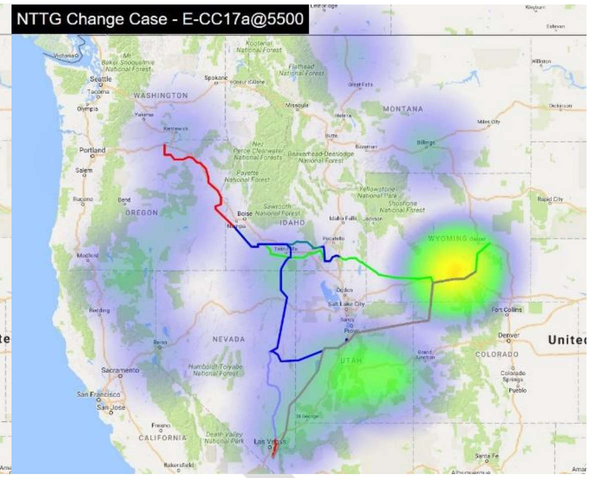



Figure 36

Again Change Case E-CC17a in Figure 36 has the same issue as Change Case E-CC20a in Figure 32, given the relatively long distances of the ITPs, the local integration performance issues in Wyoming are solvable.

## VI. Impacts on Neighboring Regions

The TWG monitored the impacts of projects under consideration for the Draft Regional Transmission Plan on neighboring Planning Regions through each Change Case. TWG found that the IRTP or the alternative Change Case plans did not impact neighboring Planning Regions.

## VII. Reliability Conclusions

- Based on the above study results, the TWG concludes that the NTTG area is not reliably served in the year 2026 without including the following non-Committed regional projects. When these non-Committed projects are included, the NTTG area requirements can be met:
    - Boardman to Longhorn (formerly Hemingway)
    - The Energy Gateway projects including segments:
        - Windstar-Aeolus 230 kV
        - Aeolus-Clover 500 kV
        - Aeolus-Anticline 500 kV
        - Anticline-Populus 500 kV
        - Populus-Cedar Hill-Hemingway 500 kV
    - Antelope Transmission Project including:
        - Antelope – Borah 345 kV

    - Antelope – Goshen 345 kV
    - Antelope 345/230 kV transformers and interconnection facilities
- The ITPs do not solve NTTG's reliability performance issues without the non-Committed regional projects and have not been included the NTTG dRTP.

# VIII. Economic Evaluations

In order to determine whether the IRTP or a Change Case transmission plan was more cost-effective, the calculation and evaluation of certain economic metrics in the IRTP and in the various Change Cases were required. The transmission plan, with some or all of the non-Committed projects and Alternative Projects, is the most "efficient or cost-effective" will be included in the Draft Regional Transmission Plan. From the Biennial Study Plan, the metrics to be evaluated are the capital related costs, power flow losses, and reserves. The economic evaluations for the IRTP and the Change Cases are discussed below.

## A. Capital Related Cost Metric

Development of the capital related cost metric required three steps to complete. The first step was to validate the Project Sponsor's Q1 submitted project capital cost. The validation was completed by comparing the Project Sponsor's submitted capital cost to the output results of the TEPPC Transmission Capital Cost Calculator, an MS Excel spreadsheet. Should the submitted capital costs vary from the Calculator output by 20%, the TWG will work with the Project Sponsor and seek to resolve the cost difference. If the difference cannot be resolved, the TWG will determine the appropriate cost to apply in the study process. If the Project Sponsor did not submit project capital cost, then the TWG developed the project's capital cost using the TEPPC Transmission Capital Cost Calculator output. The analysis results from this first step is shown in Table 3.

**Project Capital Cost Estimates**

Validate Cost Estimate

| | Acceptable | iRTP non-Committed | | | |
|---|---|---|---|---|---|
| Million 2016$ | Range | B2H | EG | CC21 | CC23 |
| | 80% | $911 | $3,922 | $3,564 | $3,368 |
| TEPPC Calculator Estimate | 100% | $1,139 | $4,903 | $4,455 | $4,210 |
| | 120% | $1,367 | $5,884 | $5,346 | $5,052 |
| Sponsor Capital Cost Estimate | 2016$ | $1,221 | Not Provided | Not Provided | Not Provided |
| Validation | | Sponsor | TEPPC Calc | TEPPC Calc | TEPPC Calc |
| Capital Cost Estimate Used | 2016$ | $1,221 | $4,903 | $4,455 | $4,210 |

**Table 3 Validation of Sponsor Estimated Costs**

The second step to develop the capital-related cost metric used the results of the first step to estimate the annual capital-related costs. The annual capital related cost was computed as the sum of annual return, depreciation, taxes other than income, operation and maintenance expense, and income taxes. A future escalation rate of 2% was used and a weighted cost of capital of 8.5% was estimated for all projects assuming 50% debt (@6%) and 50% equity (@11%) structure. The depreciation period was assumed to be 40 years for all projects. Next the total present value of annual capital related costs was computed for all projects. Table 4 provides the result of this analysis.

**Annual Capital Related Costs**

Millions of Dollars

| Expressed in 2016$ | B2H | EGW | iRTP | CC21 | CC23 |
|---|---|---|---|---|---|
| Capital Cost Estimate Used | $1,221 | $4,903 | $6,124 | $5,675 | $5,431 |
| NPV Capital Related Costs | $2,028 | $8,145 | $10,173 | $9,428 | $9,022 |
| Difference from iRTP | | | | -7.3% | -12.2% |

**Table 4 Estimated Capital Related Cost Estimates**

The third step was to levelize[15] the net present value annual capital related costs for the IRTP and the Change Case plans. Table 5 provides that levelized capital related cost for the IRTP and the Change Case plans.

**Levelized Capital Related Costs**

Millions of Dollars

| Expressed in 2016$ | | | | | |
|---|---|---|---|---|---|
| Levelized Capital Related Cost | $179 | $720 | $899 | $833 | $797 |
| Difference from iRTP | | | | ($66) | ($102) |

**Table 5 Levelized Capital Related Costs**

## B. Energy Loss Metric

### 1. Background and Method

The Energy Loss Metric is used to capture the change in energy generated, based on system topology, to serve a given amount of load. Using power flow software, the NTTG footprint

[15] Using the same economic parameters described above.

losses were evaluated. A reduction in losses for a Change Case represents a benefit because less energy is required to serve the same load.

Six of the seven NTTG Stressed Cases (excluding Case C) were analyzed. The losses for the six cases were then averaged to determine an average MW loss value. The average MW loss value was then annualized and multiplied by a 2026 nodal energy price extracted from the WECC 2026 TEPPC production cost model to produce an annualized energy loss benefit in dollars.

Note that the TWG also evaluated the use of production cost analysis software to evaluate annual energy losses. The production cost method of calculating losses resulted in lower annual losses when compared to power flow software method described above. The Technical Workgroup will continue to review the differences between the two methods in the following quarters.

## 2. Results

The Table 6 summarizes the energy loss benefit analysis for each of the affected NTTG balancing areas.

| Balancing Area | IRTP | CC21 | CC23 | Ave MW |
|---|---|---|---|---|
| **PacifiCorp** | 3,342,000 | 3,354,000 | 3,377,000 | 383.29 |
| **PGE** | 279,000 | 279,000 | 279,000 | 31.87 |
| **Northwestern** | 575,000 | 587,000 | 588,000 | 66.54 |
| **Idaho Power** | 1,245,000 | 1,313,000 | 1,308,000 | 147.11 |

**Table 6: Average Energy Loss of Powerflow cases**

| Balancing Area | IRTP | CC21 | CC23 | Ave MW |
|---|---|---|---|---|
| **PacifiCorp** | 1,816,000 | 1,818,000 | 1,817,000 | 207.4 |
| **PGE** | 605,000 | 606,000 | 606,000 | 69.1 |
| **Northwestern** | 74,000 | 74,000 | 74,000 | 8.4 |
| **Idaho Power** | 546,000 | 546,000 | 546,000 | 62.3 |

**Table 7: Average Energy Loss from Production Cost Model**

**Summary and Conclusions for Loss Analysis**

Table 6 above shows that the two change cases with fewer Gateway West transmission segments causes them to have equal to or higher losses. From a loss perspective the IRTP case has less losses and as such is the more efficient case. Losses are higher in the two change cases case because the electrical flows in the IRTP case were redistributed to fewer lines as a result of eliminating some of the proposed IRTP transmission additions in the change cases. Table 7 shows the loss results from the Production Cost Model, although a similar result, the difference between the cases was much smaller.

Several factors may be leading to the different results; in the powerflow, the peak load cases were scaled to reflect a more stressed 1 in 5 or 1 in 10 condition, whereas, the PCM database reflects a 1 in 2 condition; the hours selected may be of higher stress than the average stress of the PCM model, the area accounting in the models are not aligned, etc.

The Technical Workgroup will continue to investigate these results.

From Table 6, the loss change between the IRTP case and cases CC21/CC23 can be calculated and monetized into an annual benefit as shown in Tables 8 and 9 below:

| Balancing Area | Annual Energy (MWh) | Locational Marginal Cost ($/MWh) | Annualized Benefit ($) |
|---|---|---|---|
| **PacifiCorp** | -12,322 | $30.21 | ($372,286) |
| **PGE** | -15 | $33.07 | ($482) |
| **Northwestern** | -12,060 | $25.16 | ($303,401) |
| **Idaho Power** | -67,992 | $31.76 | ($2,154,433) |
| | | **Total NTTG Benefit** | ($2,830,603) |

**Table 8 – Energy Loss Metric Annual NTTG Benefit for Change Case 21**

| Balancing Area | Annual Energy (MWh) | Locational Marginal Cost ($/MWh) | Annualized Benefit ($) |
|---|---|---|---|
| **PacifiCorp** | -34,982 | $30.21 | ($1,056,869) |
| **PGE** | 0 | $33.07 | $0 |
| **Northwestern** | -12,994 | $25.16 | ($326,929) |
| **Idaho Power** | -63,145 | $31.76 | ($2,005,579) |
| | | **Total NTTG Benefit** | ($3,389,357) |

**Table 9 – Energy Loss Metric Annual NTTG Benefit for Change Case 23**

## C. Reserve Metric

The reserve metric evaluates the opportunities for two or more parties to economically share a generation resource that would be enabled by transmission. The metric is a 10 year incremental look at the increased load and generation additions in the NTTG footprint and the incremental transmission additions that may be included in the dRTP.

In the study cycle, Gateway West, Gateway South, B2H, SWIP North and the Cross-Tie projects were included in the analysis. To evaluate these projects, the NTTG footprint was segmented into five zones and a sixth external zone was included to study the SWIP North and the Cross-Tie projects.

The metric assumes that the parties share a pro-rata portion of a simple cycle combustion turbine (priced at $800/kw). The calculation is spreadsheet based. The six zones could potentially create 180 different sharing combinations including 30 two-party, 54 three-party, 60 four-party, 30 five-party and 6 six-party combinations. However, the transmission additions above do not enable all combinations, when the un-committed transmission is overlaid on the six zones, those 180 combinations drop to 122 viable ones (22, 36, 40, 20, 4). The uncommitted transmission segments are shown in Figure 37 below.

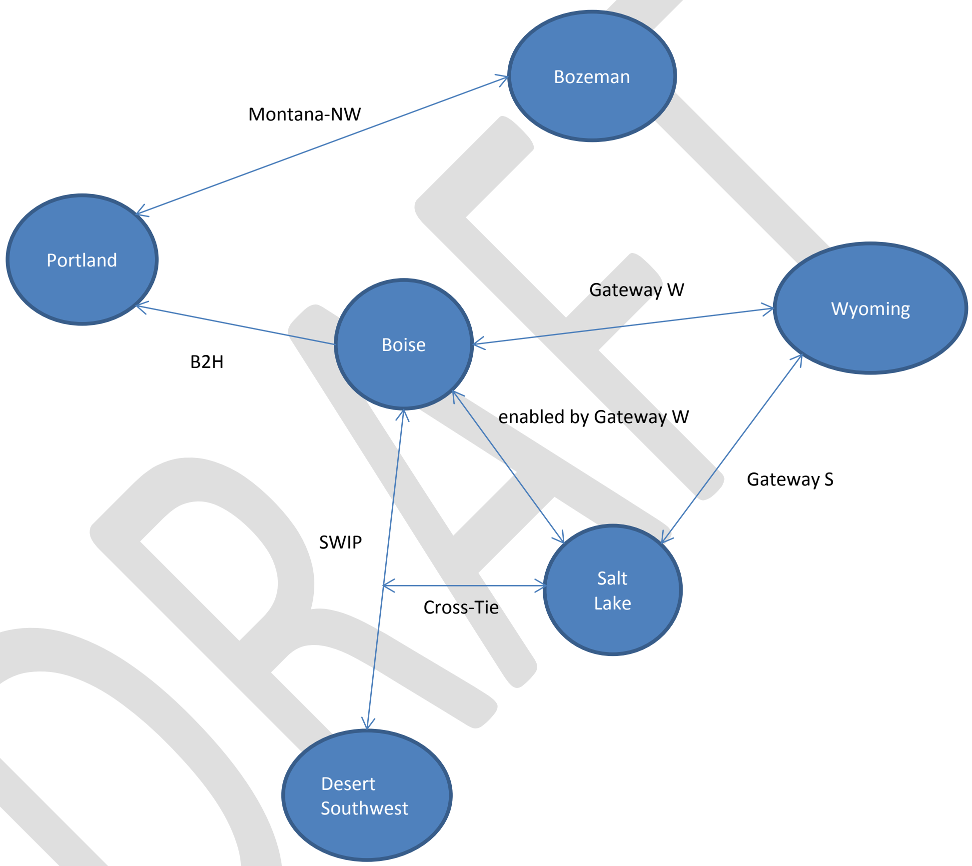





**Figure 37**

Of these 122 viable combinations, the analysis of the Annual Net Savings over the party's standalone alternative suggests that only 34 viable combinations are economic. The most economic combination for each zone are listed in Table 10 below:

| Reserve location | Receiving parties | Net Annual Savings | Source Party | Receiving Party |
|---|---|---|---|---|
| **Boise** | Bozeman<br>Portland<br>Desert Southwest | $2,896,974 | $3,340,315 | ($518,088)<br>$34,198<br>$40,549 |
| **Portland** | Bozeman | $891,190 | $265,373 | $625,818 |
| **Bozeman** | Portland | $891,774 | $626,227 | $265,546 |
| **Wyoming** | Bozeman | $487,683 | $1,154,121 | ($666,438) |
| **Desert Southwest** | Boise,<br>Bozeman,<br>Portland,<br>Salt Lake | $2,351,315 | $2,480,116 | $676,876<br>($314,778)<br>($37,271)<br>($153,629) |
| **Salt Lake** | Desert Southwest | $756,086 | $1,576,050 | ($819,964) |

**Table 10 – Distribution of savings sharing reserve capacity with the Desert Southwest via an ITP**

The Table 8 assumes that the SWIP North and/or Cross-Tie projects are constructed to enable a reserve transaction with the Desert Southwest. Without the ITP projects, the number of viable combinations drops to seven, the top five are listed in Table 11:

| Reserve location | Receiving parties | Net Annual Savings | Source Party | Receiving Party |
|---|---|---|---|---|
| **Boise** | Bozeman<br>Portland | $946,473 | $2,039,780 | ($946,120)<br>($147,187) |
| **Portland** | Bozeman | $891,190 | $265,373 | $625,818 |
| **Bozeman** | Portland | $891,774 | $626,227 | $265,546 |
| **Wyoming** | Bozeman | $487,683 | $1,154,121 | ($666,438) |
| **Salt Lake** | Bozeman | $483,710 | $1,302,563 | ($818,853) |

**Table 11 – Distribution of savings sharing reserve capacity within the NTTG footprint**

It should be noted that this metric includes generation capital costs in its evaluation and, as such, may only be appropriate for cost allocation purposes and should not be a driving factor in the selection of a dRTP. Whether these cost savings warrant jointly sharing the costs of reserve capacity is up to the parties to decide. The sharing of the estimated annual net savings between the parties is expected to be difficult as typically the receiving zone is exposed to transmission costs to enjoy the reserve benefit and the source zone does not. The source zone generally enjoys the greater positive benefit.

For the NTTG metric analysis, the IRTP and the two alternative Change Cases each support the viable economic combinations. Since these change cases could contain the same benefit value, the Change in Reserve metric does not factor into the dRTP selection decision.

## D. Metric Analysis Conclusion – Incremental Cost Comparison

The sum of the annual capital-related cost metric, loss metric (monetized) and reserve metric (monetized) calculated an incremental cost for the IRTP and the Change Case plans (see Table 12 and 13). The set of projects (either the IRTP or a Change Case plan) with the lowest incremental cost, after adjustment by the plans effects on neighboring regions will then be incorporated within the dRTP. Note that the incremental cost is computed as the levelized annual capital related cost minus NTTG loss benefit minus monetized reserve benefit.

**Change Case Metric Difference from IRTP**

| | Negative is a Benefit | |
|---|---|---|
| Metric | CC21 - IRTP | CC23 - IRTP |
| Levelized Cap. Related Cost | ($65.81) | ($101.70) |
| NTTG Losses - Monetized | $2.83 | $3.39 |
| NTTG Reserve - Monetized | $0.00 | $0.00 |
| Total Difference | ($62.98) | ($98.31) |

**Table 12 Change Case Metric Estimate Difference from IRTP**

**Incremental Cost**
**2016 $**

| Case | Difference from IRTP | Incremental Cost |
|---|---|---|
| IRTP | | $899.12 |
| CC21 | ($62.98) | $836.13 |
| CC23 | ($98.31) | $800.81 |

**Table 13 Incremental Cost Estimates**

# IX. Draft Regional Transmission Plan

Based on the reliability and economic conclusions discussed above, the more efficient or cost-effective plan, based on the studies in this report, is Change Case 23 which is a staged variant of the IRTP. For the transfers submitted in quarter 1, the facility segments shown in Figure 38 were not necessary for the transfers studied in the change cases. These segments would likely be necessary at higher transfer levels.

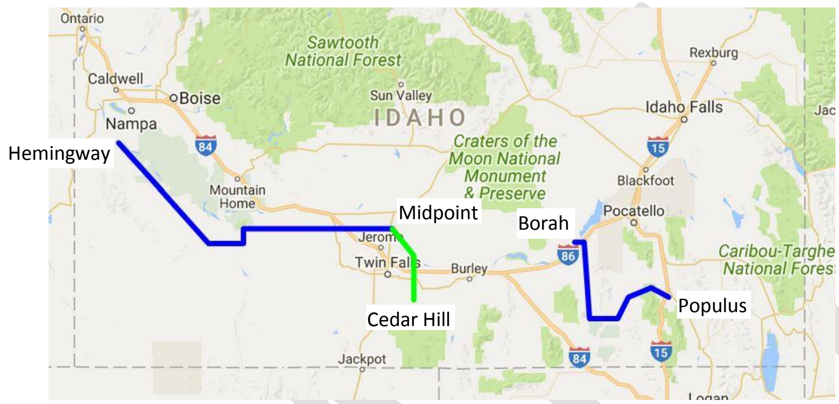



Figure 38 - IRTP segments not included in dRTP

The Figure 39 illustrates the segments included in the dRTP.

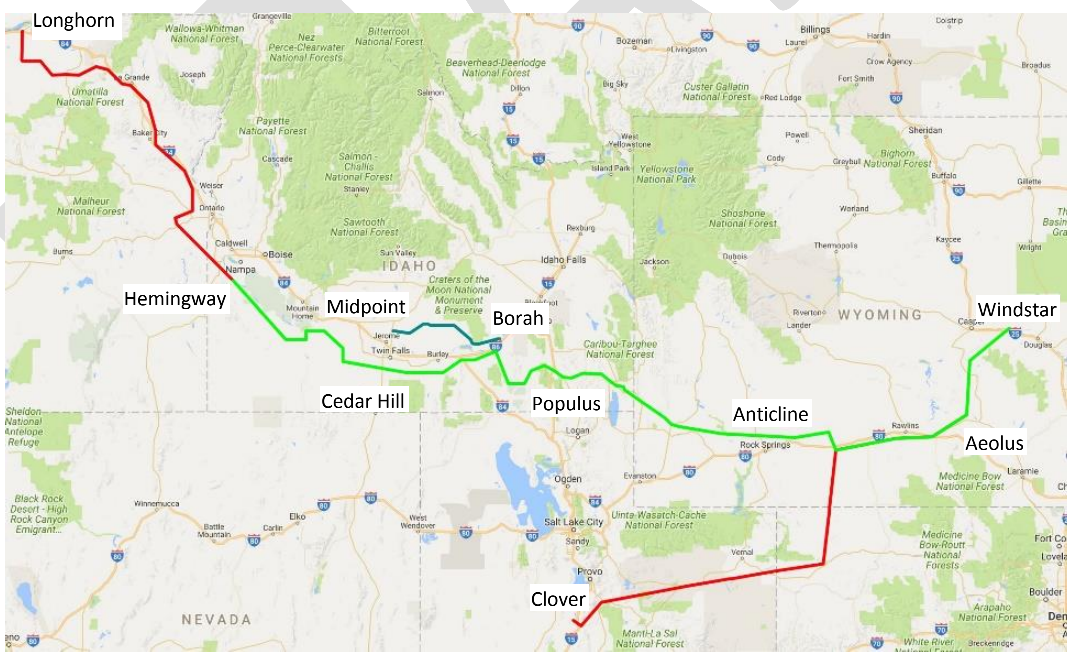



Figure 39 - dRTP Projects

# X. Lessons learned in Q1 through Q4

## A. Study plan changes

## B. Data submittals in Q1 and Q5

# XI. Robustness sensitivity studies - Q5, Q6

# XII. Public Policy Consideration - Q5, Q6

# XIII. Cost Allocation Evaluation - Q5, Q6

## Revision History

| Version | Date | Comment | Author |
|---|---|---|---|
| Version 1 | 11-21-16 | Version for internal review prior to public review and comment | R Schellberg |
| Version 2 | 12-30-16 | Version for public review and comment | |
| | | | |
| | | | |